STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2003-914

April 16, 2004

MAINE NATURAL GAS CORPORATION
Proposed Tariff Revisions for Index and Fixed Price Option Rates and to Implement Gas Cost Reconciliation Mechanism
(35-A M.R.S.A. §§ 307 and 4706)

ORDER

Welch, Chairman; Diamond and Reishus, Commissioners

I. SUMMARY

We approve Maine Natural Gas Corporation's (MNG or the Company) proposed changes to its Indexed and Fixed Price Options as described in this Order. We also approve full cost of gas reconciliation to take effect immediately, unless MNG prefers to wait until implementation and allocation issues are resolved through further discussions with the Office of the Public Advocate (OPA) and Staff. Finally, we require a review of MNG's distribution revenue requirements and earnings.

II. BACKGROUND

A. Docket No. 96-786

On December 17, 1998, we approved an alternative rate plan for MNG (then named CMP Natural Gas). The plan included a 5-year base distribution rate freeze. Customers would choose the manner in which they wished to purchase gas from MNG, either under the Index Price Option (IPO), which offered a monthly price based on reported market futures price indexes, or under the Fixed Price Option (FPO), for which price was fixed for a prescribed term of between 3 and 24 months. In addition, recognizing that rates for the interstate pipelines that would serve the LDC were subject to FERC jurisdiction, we allowed MNG to seek rate adjustments for changed upstream pipeline capacity costs. Finally, we granted the Company authority to negotiate individual special rate contracts that vary from the Company's scheduled rates without regulatory review. MNG's rate plan expires March 31, 2004.

B. Procedural History

On December 12, 2003, pursuant to 35-A M.R.S.A. §§ 307 and 4706 and Chapter 120 of the Commission's Rules, Maine Natural Gas Corporation (MNG) filed proposed revisions to its Index Price Option (IPO) and Fixed Price Option (FPO) rate schedules, pages 20.0 and 20.1. MNG initially sought authorization to modify its IPO and FPO rate schedules as follows: 1) to reduce the offered time periods for its FPO offerings, which range from 3- to 24- months, to 6- and 12- months and to change the customer enrollment periods from monthly to semi-annually in September and March; 2) to remove the heating oil component in its commodity pricing formula and to set the commodity price on a 100% gas plus upstream transportation index to better reflect natural gas costs; and 3) to initiate a gas cost reconciliation, or "true up," mechanism so that it may recover its actual gas costs associated with its IPO and FPO customers, but not gas costs associated with its negotiated special contracts. MNG argued that these changes are necessary due to changed price levels and volatility in the gas markets since its initial rate plan was approved.

The Commission issued Notice of this proceeding on December 19, 2003 and established an intervention date of January 6, 2004. The Staff issued Advisor's Data Request No. 1 on December 19, 2003.

At the request of the Hearing Examiner, Maine Natural Gas provided notice to all general service customers by separate mailing on December 22 indicating that MNG's request for rate changes and gas cost reconciliation was pending and that it sought implementation of a new formula for its IPO rate to be effective January 1, 2004. The letter also advised customers to contact the Commission to participate in, or learn more about, this proceeding.

Because of the immediacy of the proposed implementation date for the proposed revised IPO, the Staff held a preliminary conference with MNG and OPA on December 23, 2003 to discuss with MNG the details of its filing and its requested implementation schedule. The Hearing Examiner granted MNG's request for protective order from the bench, and portions of the conference were held *in camera*.

MNG asked for a waiver of the 30-day statutory time period established in 35-A M.R.S.A. §307 to allow an earlier effective date for the revised IPO of January 1, 2004 to avoid incurring costs resulting from high gas market prices during its high volume sales months of January through March. We declined to approve the IPO formula changes on less than the statutory notice at our December 31, 2003 deliberations because of insufficient time for notice of this proceeding to customers. In addition, MNG had not yet provided full information about its past years of experience with this formula. Furthermore, we did not find MNG's reasons for requesting approval on less than the statutory notice to constitute good cause.

An initial hearing among all parties and proposed interveners was held on January 6, 2004. Timely petitions to intervene were filed by the Office of the Public Advocate (OPA) and Bangor Gas Company (BGC). The Hearing Examiner granted intervention for OPA and BGC, the latter on a limited basis. BGC was granted discretionary intervention and is restricted to receiving only non-confidential information.

By Order Approving Changes to Index Rate Options dated January 13, 2004, the Commission authorized MNG to change its IPO to remove the heating oil component in its commodity pricing formula and to set the commodity price using the NYMEX gas futures only. The Commission also authorized MNG to include its hedged basis cost in its IPO rate calculation. The Commission did not address what rate MNG should use after the hedged contract period expired in March 2004.

MNG originally proposed that revised FPO rates and terms become effective on March 1, 2004 "to avoid a gap in the availability of the FPO rate." The Company later modified its request to seek final approval by April 1, 2004 along with its request for approval of reconciliation.

On March 18, 2004, an Examiner's Report was issued. Exceptions and comments were received from the OPA and MNG.

III. DESCRIPTION OF PROPOSALS

A. Index and Fixed Price Options

1. Remaining IPO Issue

In our January 13, 2004 decision the Commission allowed MNG to set IPO rates based on its contract to hedge basis risk. We did not reach a conclusion as to how MNG should determine the basis cost[1] to include in both IPO and FPO rates after that contract ends in March. MNG has proposed using the contract price, if MNG has hedged basis for the applicable time period, and, if not, the published projected monthly basis costs for Dracut. If the projected price for basis at Dracut is not published, MNG proposed to use projected basis at Tetco M3 (NY), adjusted for the different locations.

After reviewing the information provided, we will authorize MNG to calculate basis as it proposed. We considered requiring MNG to use an average of the historical basis at Dracut for similar months. However, because Dracut is a relatively new trading point, the historical data is limited and may not accurately represent the upcoming periods. We note that much of the published information for Dracut basis is provided to subscribers only and we will require that MNG be able to support its rates with information that may be publicly provided to its customers.

2. Fixed Price Option

MNG has proposed two changes to its fixed price option. The first is changing the formula to remove the oil component and to change how basis is determined. The second is to reduce the number of enrollment periods for the FPO and reduce the number of terms for which customers may sign up. We discuss each separately.

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[1] The basis cost can be thought of as similar to a delivery charge. Strictly speaking, it is the difference in cost between a central trading hub, in this case Henry Hub which is where NYMEX trades are priced, and the cost of gas at or near the LDC's service area. For MNG, Dracut Massachusetts appears to be the most relevant local cost point.

a. Calculation of FPO Formula

MNG proposes to make changes to its FPO calculation similar to the changes made in the IPO calculation. It requests approval to use 100% NYMEX natural gas futures instead of 50% natural gas and 50% oil in its pricing formula. It also asks to substitute the fixed basis already included in the formula with either the actual hedged basis cost or, if necessary, another rate approved by the Commission. In discussions with MNG, it appears that it intends to hedge basis costs. As with the IPO calculation, MNG has stated that this formula will provide a better representation of its actual cost of gas than the previous formula. As it has been doing to date, MNG will use the NYMEX contract settlement date to set the price of gas.

As with the IPO, we concur that the change in the formula to use the NYMEX natural gas futures only is reasonable and should result in gas rates that are closer to MNG's actual costs to provide gas to its customers. Regarding the basis, we agree that MNG should use the contract price for hedged basis where applicable. If for some reason MNG does not contract for basis prior to a specific FPO period, we will require MNG to calculate basis for the FPO based upon an average of the weighted actual basis at Dracut for similar periods over the prior two years. If after making this calculation, MNG has reason to believe that the results are not reflective of the upcoming period, when it files its FPO rates, it can propose other methods along with an explanation as to why the historical basis would not be suitable.

b. FPO Term and Enrollment Periods

Currently MNG allows its customers to enroll in the FPO each month for periods of 3, 6, 9, 12, 15, 18, 21 or 24-month terms.[2] MNG proposes now to reduce the enrollment period to once annually for a term of either 12 or 24 months.[3] MNG states that because of the limited number of customers and the associated volumes it is not able to hedge its gas for similar terms and therefore, has a greater risk of its actual costs not matching the rates it is charging its customers. In addition, if not enough customers with the necessary volumes elect the 24-month term, MNG requests authority to eliminate that option.

We recognize that while it is generally preferable to give customers choices, it is not always possible. It is apparent that it is not feasible for MNG to offer the broad range of FPO terms given the current volatile market conditions and the small volumes that these offerings attract each month. In reviewing MNG's proposed change, we noted that the majority of customers who had signed up for the FPO elected

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[2] MNG agreed that deferral of a decision on its FPO proposals until the end of March would not pose a problem because there were only a few customers whose FPO options ended in March.

[3] In its initial proposal, MNG proposed to have two enrollment periods per year and offer six and twelve month terms.

the 12-month term. Therefore, we will allow MNG to limit the fixed price options it offers to 12- and 24-month terms.[4] We will also allow MNG to eliminate the 24-month term when not enough customers sign up for this option.

Regarding the enrollment period, we will allow MNG to hold one month-long enrollment period during the month of August for service commencing September 1, as proposed in its February 13, 2004 update. This provides a longer sign-up period than it currently offers. This seems appropriate if MNG offers the FPO only once each year. In addition, MNG has stated that it will allow a 30-day grace period for residential customers who wish to enroll in the FPO.

In its February 13, 2004 filing, MNG indicated that it would provide a fair transition by allowing existing FPO customers whose FPOs expire between now and the end of the next enrollment period (August 31, 2004) to join an existing FPO that expires August 31, 2004 or the IPO. This will position them to then select either the FPO effective September 1, 2004 or the IPO.

New customer transition provides different challenges. New residential or small commercial customers coming onto MNG's system will be allowed to sign up for either the remaining term of the 12-month FPO or the monthly IPO. MNG proposes to allow new large users taking GS-2 service to join the FPO during the first four months of the FPO term (i.e. late sign-on for these customers would extend through December 31, 2004.) Thereafter, new GS-2 customers will be billed under the IPO until the next FPO enrollment period in August 2005.

B. <u>Reconciliation</u>

In its December 12, 2003 filing, MNG proposed that its revised IPO and FPO pricing mechanisms include a true-up provision to reconcile actual gas costs with revenues recovered from customers. Initially, MNG stated that it would compute the true-up amount after subtracting from the total monthly gas cost the cost associated with negotiated rate contracts. It would then compare the remaining amount with the amount charged to its IPO and FPO customers and reconcile the difference, allocating it to its IPO and FPO customers based on the proportional volume share of each pricing option.

MNG also initially proposed that for IPO customers, the true up would occur in the bill issued two months following the sales month. A final reconciliation would be done for the 12 months ending in July each year. For FPO customers, MNG would track the true-up balances monthly but would apply the net true-up basis annually. Consequently, next year's FPO price would include the estimated cost of gas for the upcoming period as well as an adjustment for reconciliation of the past year's FPO

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[4] Staff encouraged MNG to offer the 24-month option because it has been a popular option for electric rate contracts.

revenues and costs. MNG would maintain a deferred gas cost and revenue account on its books to track these adjustments.

Subsequently, in its February 13, 2004 filing, MNG refined its reconciliation proposal to have the annual reconciliation adjustment reflected in customers' bills commencing September 1 as a rate for recovery of over- or under- collections accruing during the prior July 1 through June 30 period. MNG also proposes that a transitional reconciliation for the period February 1, 2004 through June 30, 2004 be allowed.[5] In its March 25th exceptions, MNG clarified that it would reconcile costs and revenues for IPO customers separately from FPO customers, however, other gas costs of unknown origin would be allocated to IPO and FPO customers based on the proportional volume share of each pricing option.

The February 13, 2004 filing included confidential attachments showing MNG's proposal for calculating true-up amounts starting with the calculation of a "normalized cost of gas." In the last technical conference, MNG agreed that further details on how the cost of unaccounted-for gas and special contract gas purchases would be allocated among customers and the accrual of interest on the over- or under-collections would have to be clarified in a technical conference with Staff and OPA.

IV. ANALYSIS

A. Authority

The Commission may approve any reasonable alternative ratemaking mechanisms for gas utilities "to promote efficiency in operations, create appropriate financial incentives, promote rate stability and promote equitable cost recovery." 35-A M.R.S.A. §4706. In doing so, it must consider appropriate consumer and competitive safeguards. 35-A M.R.S.A. §4706(4). Its other considerations may include: "the costs of regulation, the benefits of the rate plan to the utility and to ratepayers, the impact on economic development, the reallocation of risk between investors and ratepayers, the development of a competitive market for gas services that are not natural monopolies," and any other relevant factor. 35-A M.R.S.A. §4706(1).

Section 4703 of Title 35-A authorizes reconciliation of gas costs and revenues using a cost of gas adjustment mechanism. Chapter 43 of the Commission's Rules specifies how cost of gas rates are to be determined.

The Commission may, as part of an alternative rate-making mechanism, waive or modify the statutory cost of gas adjustment clause requirements (contained in 35-A M.R.S.A. § 4703) "to the extent necessary to promote efficiency in operation,

[5] The Company should work with Staff to determine whether the transitional reconciliation period should begin February 1 or some other date consistent with the Company's position regarding the conditions we have stated herein.

appropriate financial incentives, rate stability or equitable cost recovery." 35-A M.R.S.A. §4706(8). The statute further provides:

> Prior to the adoption of a new or replacement alternative rate plan or renewal of any existing alternative rate plan, the commission shall, in order to ensure that rates at the starting point of the plan are just and reasonable, conduct a revenue requirement and earnings review pursuant to the standards of section 301. In conducting such a review under this subsection, the commission, at its discretion, may conduct the review in a manner designed to minimize the cost of the review to ratepayers.

35-A M.R.S.A. §4706(3).

When we approved MNG's current (some word missing here) into place, we specified that MNG could request changes to the upstream capacity costs contained in its rates pursuant to Section 307 if it believed it necessary. *See* Docket No. 96-786, Order Approving Rate Plan (Dec. 17, 1998) at 5. On January 13, 2004, we approved changes related to basis and the composition of the formula for calculating the Company's IPO formula through March 2004. *See*, in this docket, Order Approving Changes to Index Price Option Rate Formula (Jan. 13, 2004).

B. <u>Prior Revenue Requirement and Earnings Review</u>

The OPA argues that the Commission may not approve MNG's reconciliation proposal without first conducting a revenue requirement and earnings review for two reasons. First, OPA argues that gas cost and revenue reconciliation is such a substantive departure from the rate plan originally approved by the Commission that it amounts to a "new or replacement alternative rate plan" under Section 4706(3). Second, OPA argues that the expiration of MNG's current rate plan on March 31, 2004 is sufficient to trigger the statutory requirement for a revenue requirement and earnings review because the Commission will need to either renew MNG's current rate plan or approve a "new or replacement" rate plan for MNG's operations going forward. OPA further argues that because MNG has never been the subject of a rate investigation, it is important to do one even if MNG reverts to traditional regulation. OPA commits to working with the Company and Commission "to design a low-cost or streamlined proceeding that will comply with applicable statutes while minimizing burdens to the Commission or the parties."

MNG argues that its reconciliation proposal does not trigger the revenue requirement and earnings review provision of Section 4706(3) because the alternative rate plan – a 5-year rate freeze -- applies only to MNG's distribution, not commodity, rates. MNG argues that while the Commission approved MNG's IPO and FPO pricing formulas for similar reasons, e.g. "to ensure that MNG's risk of investment in its start-up system fell on shareholders, not ratepayers," it did not subject these elements to a freeze. MNG suggests that the revenue requirement and earnings review is necessary only for those aspects of rates that will fall within the proposed rate plan. Accordingly, MNG argues that because it is seeking only to change the commodity portion of its rates, the streamlined review of MNG's historic commodity earnings that has already been accomplished in this proceeding is adequate to satisfy the requirements of Section 4706(3) in this instance. MNG argues that this is consistent with the Legislature's underlying purpose in adopting Section 4706, which was to promote the availability and expansion of natural gas service in Maine by allowing the PUC flexibility to streamline regulation, including cost of gas adjustment mechanisms.

C. <u>Decision</u>

1. <u>Need for Revenue Requirement and Earnings Review</u>

We agree with MNG that converting from its original rate structure to a reconciled gas cost rate structure would not trigger Section 4706(3). Section 4706(3) does not specify that a revenue requirement and earnings review is necessary when a utility that has operated under an alternative rate plan "reverts" to traditional regulation. This is consistent with the purpose of the provision, which is to establish a fair starting point when embarking on an alternative rate plan.

We conclude that MNG is reverting to traditional regulation of its commodity costs (and also, perhaps, of its distribution rates) and not adopting a new or replacement alternative into plan nor renewing the currentrate plan with another alternative rate plan. Thus, we determine that we may adopt a fully reconciled cost of gas clause for MNG at this time without first conducting a revenue requirement and earnings review.

We nevertheless conclude that, under the circumstances, we will undertake a review of distribution revenue requirements to ensure that, under traditional regulation principles, MNG's rate are just and reasonable.

Throughout the proceeding in which we approved MNG's rate plan, we made clear that we provided MNG with considerate ratemaking latitude because its proposed plan allocated substantial risk to shareholders. For example, in addressing the question of whether MNG's gas cost projections were understated, we said:

> As in *Bangor Gas,* the condition that investors will bear the risks of project failure eliminates the need for us to ensure that CMP NG's projected gas costs are accurate because ratepayers will not be subject to the risk that rates will be higher than currently projected. If ratepayers were at risk for CMP NG's gas costs, we would require a more complete demonstration of how it would obtain supplemental supplies and what effects this would have on overall gas costs. With the condition of investor risk, however, we need only review CMP NG's proposed resource

> plan to determine that it is realistic and that it will have adequate gas supplies to provide the service that it proposes.

Docket No. 96-786, Order (Phase 2), (Aug. 17, 1998) at 25.

Similarly, with regard to the proposed IPO and FPO pricing options we concluded:

> We find CMP NG's proposed rate offerings acceptable and do not believe that a different treatment of gas costs (such as a traditional cost of gas adjustment (CGA)) is necessary. Competition, coupled with the placing of project failure risk squarely on shareholders, substantially reduces our concern over <u>how</u> rates are developed. Customers may decide for themselves whether or not they find the price structure offered by CMP NG attractive before committing to it. We decline here to second guess the entrepreneurial instincts of business developers where the risks of failure to achieve market acceptance do not fall on ratepayers.

<u>Id</u>. at 26.

We also provided the following guidance on necessary terms of a revised rate plan proposal:

> We will grant service authority to CMP NG in all of its proposed project area, if it presents an acceptable revised proposal. First CMP NG should revise its rate plan to assure us that CMP NG's proposal has addressed the concerns we have identified with respect to particular rates, that the rates will remain stable over time, and that the risk of errors in project cost or revenue estimates will not be borne by ratepayers. … We insist, however, that – whatever price levels CMP NG chooses to offer – ratepayers not be at risk for rate increases to save investors from the consequences of their own poor projections.

<u>Id</u>. at 39.

Consistent with the statements in our prior orders, we agree with the OPA andconclude that the degree of scrutiny we accorded both MNG's gas and distribution rates was more limited than it would have been if shareholders had not borne the risks of errors in cost or price projections.

Thus, while section 4706 does not <u>compel</u> that we conduct a revenue requirement and earnings review for MNG, one is warranted at this juncture because we have not previously established that MNG's distribution rates are in accord with traditional cost of service principles. Our cursory review in this proceeding of MNG's commodity gains and losses during each of its years of operation to date does not satisfy this objective. Accordingly, we will require a reasonable review of MNG's distribution revenue requirements and earnings. We encourage the parties to come to agreement with Staff on the appropriate form and detail of this review. In particular, we urge the parties to avoid a proceeding that would impose costs on ratepayers that would dwarf any benefits of the inquiry.

With the expiration of the rate freeze on March 31, 2004 and its reversion to a more traditional treatment of gas costs through reconciliation, only one non-traditional element remains in MNG's regulatory structure. Parties should discuss whether, with reversion to traditional base rate regulation, MNG should continue to have authority to enter into special contract arrangements without prior Commission review, and, if so, how to ensure that ratepayers will not subsidize the service and facilities provided to special contract customers.

2. <u>Policy</u>

The Examiner's Report raised the question of whether MNG should be allowed a fully reconcilable cost of gas (COG) clause as a matter of current and developing regulatory policy. The Report described the arguments in favor of a fully reconciled COG clause for MNG. First, gas costs represent a major portion of total costs for MNG, as they do for most local distribution companies (LDC). Thus, significant gains or losses on gas costs, which may not be under the control of MNG, can have a very real impact on income. Second, gas costs are primarily driven by the market, particularly changes in the overall cost of gas, typically defined as the NYMEX price for gas at Henry Hub, and the basis differential, which is the difference between the Henry Hub price and the price at a local delivery point such as Dracut Massachusetts. Both elements have shown considerable volatility in recent years. This underlying level of volatility is fully outside MNG's control. Finally, the other two LDC's in Maine currently have fully reconciled COG clauses.

The Report also developed the arguments against full reconciliation. First, the fact that gas costs are large indicates that it is an item to which an LDC should pay close attention if it is behaving responsibly. A fully reconciled COG provides no direct incentive to minimize the cost of gas, the primary protection for customers is an after-the-fact review of gas procurement actions by Staff and interveners. Regulators must oversee utility gas purchasing and disallow imprudent gas costs through litigation. It may be better policy, where possible, to provide direct financial incentives for prudent behavior .

The Staff proposed a sharing mechanism with an annual bandwidth of plus or minus 2½% around actual gas costs as a gas cost risk-sharing mechanism to provide such an incentive.

We decline to adopt a partially reconciled clause that would expose MNG to purchasing risk, and will allow full reconciliation. We do so principally because we see no policy reason to treat MNG differently from the other LDCs in Maine.

We prefer to consider questions about what gas cost purchasing goals we would establish for gas utilities in a proceeding that results in a broadly applicable policy, after full development of the record on the policy issues and possible sharing mechanisms.

IV. CONCLUSION

We approve changes to the FPO and IPO pricing option formulas consistent with changes we allowed to the IPO formula in our January 14, 2004 Order. We also approve changes to the FPO option to limit this offering to either a 12-month or 24-month term beginning on September 1st each year.

Finally, we approve full cost of gas reconciliation for MNG and also find that a revenue requirement and earnings review of MNG's distribution rates is warranted at this time. We direct the parties to find agreement on the form and detail of this review, cautioning that it should be done in a way that the burdens of the proceeding do not overwhelm the benefits of such a review. MNG may begin reconciliation immediately on the condition that it agree to accept our evaluation of the appropriate method of allocating gas costs among its customer groups, to the extent our evaluation is different from the Company's, in its transitional reconciliation review. Alternatively, MNG may work with parties to determine allocations prior to initiating reconciliation.

Dated at Augusta, Maine, this 16th of April, 2004.

BY ORDER OF THE COMMISSION

Dennis L. Keschl
Administrative Director

COMMISSIONERS VOTING FOR: Welch
Diamond
Reishus

NOTICE OF RIGHTS TO REVIEW OR APPEAL

5 M.R.S.A. § 9061 requires the Public Utilities Commission to give each party to an adjudicatory proceeding written notice of the party's rights to review or appeal of its decision made at the conclusion of the adjudicatory proceeding. The methods of review or appeal of PUC decisions at the conclusion of an adjudicatory proceeding are as follows:

1. Reconsideration of the Commission's Order may be requested under Section 1004 of the Commission's Rules of Practice and Procedure (65-407 C.M.R.110) within 20 days of the date of the Order by filing a petition with the Commission stating the grounds upon which reconsideration is sought.

2. Appeal of a final decision of the Commission may be taken to the Law Court by filing, within **21 days** of the date of the Order, a Notice of Appeal with the Administrative Director of the Commission, pursuant to 35-A M.R.S.A. § 1320(1)-(4) and the Maine Rules of Appellate Procedure.

3. Additional court review of constitutional issues or issues involving the justness or reasonableness of rates may be had by the filing of an appeal with the Law Court, pursuant to 35-A M.R.S.A. § 1320(5).

Note: The attachment of this Notice to a document does not indicate the Commission's view that the particular document may be subject to review or appeal. Similarly, the failure of the Commission to attach a copy of this Notice to a document does not indicate the Commission's view that the document is not subject to review or appeal.